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Dr. Raymond W. Waldo
Station Manager
San Onofre

March 24, 2003

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, D.C. 20555-0001

Subject: **Docket Nos. 50-361, 50-362**
Licensee Event Report No. 2003-001
San Onofre Nuclear Generating Station, Units 2 and 3

Gentlemen:

This submittal provides Licensee Event Report (LER) 2003-001 describing an automatic reactor trip event that occurred at Unit 2 on February 1, 2003. The reactor trip and subsequent initiation of the Auxiliary Feedwater System are reportable in accordance with 10CFR50.73(a)(2)(iv)(A). These events did not affect the health and safety of either plant personnel or the public.

Any actions listed are intended to ensure continued compliance with existing commitments as discussed in applicable licensing documents; this LER contains no new commitments. If you require any additional information, please so advise.

Sincerely,

Raymond Waldo

Enclosure

cc: E. W. Merschoff, Regional Administrator, NRC Region IV
C. C. Osterholtz, NRC Senior Resident Inspector, San Onofre Units 2 & 3

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NRC FORM 366 (7-2001) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104 EXPIRES 7-31-2004

Estimated burden per response to comply with this mandatory information collection request: 50 hours. Reported lessons learned are incorporated into the licensing process and fed back to industry. Send comments regarding burden estimate to the Records Management Branch (T-6 E6), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by internet e-mail to bjs@nrc.gov, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202 (3150-0104), Office of Management and Budget, Washington, DC 20503. If a means used to impose information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

1. FACILITY NAME	2. DOCKET NUMBER	3. PAGE
San Onofre Nuclear Generation Station (SONGS) Unit 2	05000-361	1 OF 5

4. TITLE

Incorrect Test Connection Results in Automatic Reactor Trip

5. EVENT DATE			6. LER NUMBER			7. REPORT DATE			8. OTHER FACILITIES INVOLVED	
MO	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO	MO	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
									SONGS Unit 3	05000-362
02	01	2003	2003	001	00	03	24	2003	FACILITY NAME	DOCKET NUMBER

9. OPERATING MODE	1
10. POWER LEVEL	100

11. THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check all that apply)

20.2201(b)	20.2203(a)(3)(ii)	50.73(a)(2)(i)(B)	50.73(a)(2)(ix)(A)
20.2201(d)	20.2203(a)(4)	50.73(a)(2)(ii)	50.73(a)(2)(x)
20.2203(a)(1)	50.36(c)(1)(i)(A)	X 50.73(a)(2)(iv)(A)	73.71(a)(4)
20.2203(a)(2)(i)	50.36(c)(1)(ii)(A)	50.73(a)(2)(v)(A)	73.71(a)(5)
20.2203(a)(2)(ii)	50.36(c)(2)	50.73(a)(2)(v)(B)	OTHER
20.2203(a)(2)(iii)	50.46(a)(3)(ii)	50.73(a)(2)(v)(C)	Specify in Abstract below or in NRC Form 366A
20.2203(a)(2)(iv)	50.73(a)(2)(i)(A)	50.73(a)(2)(v)(D)	
20.2203(a)(2)(v)	50.73(a)(2)(i)(B)	50.73(a)(2)(vii)	
20.2203(a)(2)(vi)	50.73(a)(2)(i)(C)	50.73(a)(2)(viii)(A)	
20.2203(a)(3)(i)	50.73(a)(2)(ii)(A)	50.73(a)(2)(viii)(B)	

12. LICENSEE CONTACT FOR THIS LER

NAME	TELEPHONE NUMBER (Include Area Code)
R. W. Waldo, Station Manager, Nuclear Generation	949-368-8725

13. COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT

CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX

14. SUPPLEMENTAL REPORT EXPECTED			15. EXPECTED SUBMISSION DATE	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X	NO				

16. ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines)

On 02/01/03, while Unit 3 was defueled for Cycle 12 refueling and Unit 2 was in Mode 1 at 100 percent power, a Technician (utility, non-licensed) was conducting planned outage work on the Unit 3 relay protection cabinet (RPC), 3L070. While establishing a reference test connection within the Unit 2 RPC, 2L070, the Technician misidentified the reference terminal and made an incorrect connection to the Field Suppression Relay for the Unit 2 Main Generator.

Upon initiating the test, at 0310 PST, the error resulted in the following automatic and sequential events at Unit 2: (1) actuation of generator loss of field relay, (2) generator/turbine trip, (3) reactor trip, and (4) initiation of emergency feedwater. Systems responding to the event performed as designed. Additionally, Operator responses were correct and timely.

This event was caused by a combination of personnel error and inadequate procedural guidance. SCE will take appropriate personnel actions and improve written work instructions.

SCE concludes that this event was of low to no safety significance. There were no consequences to public health and safety.

Plant: San Onofre Nuclear Generating Station, Unit 2
Event Date: February 1, 2003

Unit 2
Reactor Vendor: Combustion Engineering
Power: 100 percent

Background:

The Main Generator Excitation and Voltage Control System has the following main functions:

- The Main Generator Excitation and Voltage Control System controls the magnetic strength of the Main Generator rotor field, which, in turn, controls the terminal voltage and reactive power of the Main Generator.

- The Main Generator Excitation and Voltage Control System automatically trips the generator excitation under upset, emergency or faulted conditions.

The Automatic Voltage Regulator (AVR) controls the voltage to the Main Exciter field. A trip signal from a Main Generator Protection Trip will initiate the AVR's suppression circuit.

The Field Suppression Relay is the master protection relay common to both channels of the AVR. Once the Field Suppression Relay is actuated, the AVR trips both channel breakers, thereby de-energizing the rotor field windings. The rotor field degradation is sensed by the Main Generator Loss of Field Relay, which initiates a turbine trip at its setpoint.

Description of the Event:

On 02/01/03, while Unit 3 was defueled for Cycle 12 refueling and Unit 2 was operating in Mode 1 at 100 percent power, a Technician (utility, non-licensed) was conducting planned functional testing of the Unit 3 Main Transformer [EL] and Main Generator [EL] protective relays within the Unit 3 relay protection cabinet (RPC) [TL], 3L070. Since the 6.9kV breaker control power needed for the test was supplied by Unit 2, the Technician attempted to establish a control power reference connection within the Unit 2 RPC [TL], 2L070. The Technician, however, misidentified the reference terminal and incorrectly connected to the Field Suppression Relay [TL] for the Unit 2 Main Generator.

The Technician initiated his test at 0310 PST, which immediately resulted in the actuation of the Unit 2 Field Suppression Relay. This initiated the following automatic and sequential events at Unit 2: (1) actuation of generator loss of field relay, (2) generator/turbine trip, (3) reactor trip, and (4) initiation of emergency feedwater. Systems responding to the event performed as designed. Additionally, Operator responses were correct and timely.

Southern California Edison (SCE) previously reported this event in accordance with 10CFR50.72(b)(2)(iv)(B) and 10CFR50.72(b)(3)(iv)(A). This follow-up Licensee Event Report is being submitted in accordance with 10CFR50.73(a)(2)(iv)(A).

Cause of the Event.

This event was caused by personnel error. The Technician made an incorrect terminal connection to the Field Suppression Relay in the Unit 2 relay protection cabinet.

SCE has also concluded that the procedural guidance was not adequate in relation to the complexity of this work and the potential consequences, which resulted in an inadequate pre-work discussion ("tailboard") and over-reliance on "skill of the craft."

Completed Corrective Actions:

A site-wide briefing was conducted to review this event and communicate management expectations to exercise caution in error-likely situations.

A physical barrier has been placed on the relay protection cabinet for each Unit to prevent unreviewed and/or unplanned access.

Planned Corrective Actions:

SCE will appropriately discipline personnel involved in this event.

SCE will also improve the procedural guidance for work within the relay protection cabinet and other areas that are subject to similar risks and consequences.

Safety Significance:

SCE characterizes this event as a decrease in heat removal by the secondary system turbine plant. The event is bounded by the safety analysis for the Loss of Condenser Vacuum (LOCV) event described in UFSAR 15.2.1.3 and 15.10.2.1.3.

The LOCV leads to a loss of normal feedwater flow and a loss of turbine load. In this event, the loss of feedwater was a direct consequence of the Main Generator/Turbine trip and slow bus transfer of auxiliary power (see Additional Information, Part B, below). Operators maintained cooling with the Auxiliary Feedwater System and Steam Bypass Control System. Because this event did not result in a loss of heat sink, SCE considers the event less severe than the LOCV. Additionally, the Main Feedwater Pumps (MFWP) could have been restarted, if needed.

An assessment of the conditional core damage probability (CCDP) and the conditional large early release probability (CLERP) for the February 1, 2003 event determined that the Unit 2 CCDP and CLERP were 4.5E-6 and 1.8E-7, respectively. The assessment was based on the reported actual component unavailability and system alignments at the time of the event.

Based on the above, SCE concludes that this event was of low to no safety significance. There were no consequences to public health and safety.

Additional Information:

A In 2002, SCE submitted LERs for the following reactor trips:

- Steam Bypass Control System (SBCS) failure due to an inadequate calibration procedure caused an automatic reactor trip. Corrective actions focused on the SBCS calibration procedure (LER 2-2002-003).

- Main Feedwater (FW) Controller failure due to age-related degradation of a controller component card caused an automatic reactor trip. Corrective actions focused on the faulty component (LER 2-2002-006).

- Pressurizer Spray Valve failure caused a manual reactor trip. The root cause investigation for the equipment failure is ongoing (LER 2-2002-007).

Corrective actions for the events listed above focused on procedural or mechanical causal factors and, therefore, would not be expected to prevent the reactor trip event reported in this LER.

- Main switchyard breaker trip due to personnel error caused a loss of offsite power and automatic reactor trip. A San Diego Gas & Electric (SDG&E) technician exceeded his authorized work scope within the SDG&E portion of the San Onofre switchyard. Corrective actions focused on establishing work controls for non-SCE personnel working in the main switchyard (LER 3-2002-001).

Although this event has some similarity to the event reported herein, SCE believes that they differ to the extent that corrective actions taken for the switchyard event would not be expected to prevent the reactor trip event reported in this LER.

B. Temporary Loss of Main Feedwater Pumps (MFWP) K005/P063 and K006/P062

Normally, upon a Main Generator/Turbine trip, a "fast" transfer of non-1E power takes place from the Unit Auxiliary Transformer (UAT) to the Reserve Auxiliary Transformer (RAT) within five to ten cycles (80-160 milliseconds). However, due to the Loss of Field trip of the Main Generator, the RAT incoming supply voltage and phase did not closely match the UAT bus voltage and phase. Consequently, a "fast" bus transfer was inhibited. The transfer relay prevented the bus transfer until the voltage had decayed below the setpoint of the residual voltage relay. This "slow" bus transfer scheme typically takes between several hundred milliseconds to a couple of seconds, depending on the motor load on the bus.

A review of the Digital Fault Recorder (DFR) traces taken during the Unit 2 trip shows that the medium voltage non-1E buses 2A03 and 2A07 experienced degraded voltage conditions for approximately 360 and 710 milliseconds, respectively. At that time, non-1E bus 2A07 was powering the in-service MFWP Lube Oil Pumps, P122 for K006/P062 and P123 for K005/P063. The degraded voltage condition in 2A07 caused the fuses for P122 and P123 to blow and the pumps stopped. Subsequently, each of the Main Feedwater Pumps tripped on low lube oil pressure.

The 2A03 and 2A07 bus voltages returned to normal upon transfer to the RAT, at which time the standby Lube Oil Pumps powered from 2A03 auto-started.

With the restoration of the medium voltage non-1E power buses and availability of MFWP lube oil, one or both of the MFWPs could have been restarted, if needed.